

**BEFORE THE PUBLIC UTILITIES COMMISSION  
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Establish Policies  
and Rules to Ensure Reliable, Long-Term Supplies  
of Natural Gas to California.

R.04-01-025

**COMMENTS OF TRANSWESTERN PIPELINE COMPANY  
ON PHASE I PROPOSALS**

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In accordance with Ordering Paragraph 7 of the Commission's *Order Instituting Rulemaking to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California* ("OIR"), Transwestern Pipeline Company ("Transwestern") hereby submits these comments on the Phase I proposals submitted by the respondent utilities on February 24, 2004 ("Proposals").<sup>1</sup>

**I. INTRODUCTION**

Transwestern commends the Commission for opening this proceeding, thereby providing a venue to address on a comprehensive and timely basis issues relating to access to the transmission systems of California's natural gas utilities and other important market structure issues. Transwestern fully supports the Commission's overarching objective of ensuring the long-term availability of reliable and reasonably priced natural

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<sup>1</sup> The respondent utilities are Pacific Gas and Electric Company ("PG&E"), San Diego Gas & Electric Company ("SDG&E"), Southern California Gas Company ("SoCalGas"), and Southwest Gas Corporation ("Southwest Gas").

gas supplies to California, and looks forward to working with the Commission and California's natural gas utilities toward that goal.

For Phase I of this proceeding, the Commission directed the respondent utilities to submit proposals for rules and guidelines for how the utilities should: (1) enter into contracts with interstate pipelines (whether new contracts or renewals of existing contracts) to meet core supply obligations; (2) provide access to liquefied natural gas ("LNG"); and (3) provide access to additional supplies of natural gas transported on interstate pipelines.<sup>2</sup> The utilities submitted their proposals on February 24, 2004.

Transwestern generally supports the proposals of SoCalGas and SDG&E (collectively, the "Sempra Utilities") for the acquisition of interstate capacity to serve core demand. Specifically, Transwestern supports the regulatory approval procedures proposed by the Sempra Utilities for new interstate capacity commitments. And Transwestern agrees that supply reliability can be enhanced by increasing supply diversity.

Transwestern has reservations, however, concerning the Sempra Utilities' proposed planning criteria for core capacity commitments. Planning based simply on historical average daily demand, as the Sempra Utilities propose, could expose core customers to the very cost risks associated with capacity shortages and spot market purchases that the Commission hopes to mitigate. Transwestern believes that core customers would be better served by adopting for the Sempra Utilities the 1-in-10 year peak-day and cold-winter planning criteria proposed by PG&E.

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<sup>2</sup> OIR, Ordering Paragraph 6.

Transwestern is also concerned that, in the pursuit of supply diversity, the California utilities may actually end up, in the long-term, reducing core reliability and increasing their commodity costs to the extent that they make supply portfolio decisions based on erroneous assumptions about future gas basin differentials, gas flows or new gas supply projects. Specifically, Transwestern believes that it would be imprudent to assume that Rocky Mountain gas will always be less expensive than other supplies, or to assume that additional Rocky Mountain supplies and/or LNG supplies will be available in the future as needed to meet core demand.

Moreover, existing supplies such as those from the San Juan and Permian basins are proven and reliable sources, and there is no guarantee that any of the interstate pipeline capacity that provides access to such basins, once relinquished by California utilities, will be available in the future. Given the relatively low cost of interstate capacity, Transwestern believes that core customers—and California in general—would be best served by requiring the utilities to maintain adequate firm access to *all* major producing basins. Maintaining access to all supply basins will ensure that reliable supplies are always available. Moreover, it is consistent with the Sempra Utilities' supply diversity proposal and a prudent step to take in light of recent history.

With respect to the issue of access to new supplies, Transwestern is concerned that automatically “rolling in” the cost of expanding utility backbone facilities necessary to accommodate new supplies, as SoCalGas and SDG&E propose, will “tilt” the playing field against traditional interstate gas supplies and mask the true costs of the incremental source of supply. Transwestern believes that ratepayers would be best served if all supplies compete on a level playing field.

Finally, Transwestern supports SoCalGas' proposal to establish a system of firm tradable rights for receipt point capacity as a means to ensure firm delivery rights from the wellhead to burner tip. Transwestern encourages the Commission, however, to explore the details of how primary receipt point rights can be matched to interstate capacity on an ongoing basis—a prerequisite for real gas-on-gas competition opportunities. Transwestern also requests clarification concerning SoCalGas' proposal to allow capacity holders to "re-contract" any part of their awarded receipt point capacity. In light of the proposed limitations on the use of alternate receipt points and the fact that alternate paths have inferior delivery rights, it is critical that capacity holders have ongoing opportunities to change their receipt points to match up with supplies. The Commission should explore the experience of pipelines like Transwestern that allow shippers to change primary delivery points on a daily basis to match up with supplies and the experience of PG&E with pooling as a mechanism to match supply and transportation.

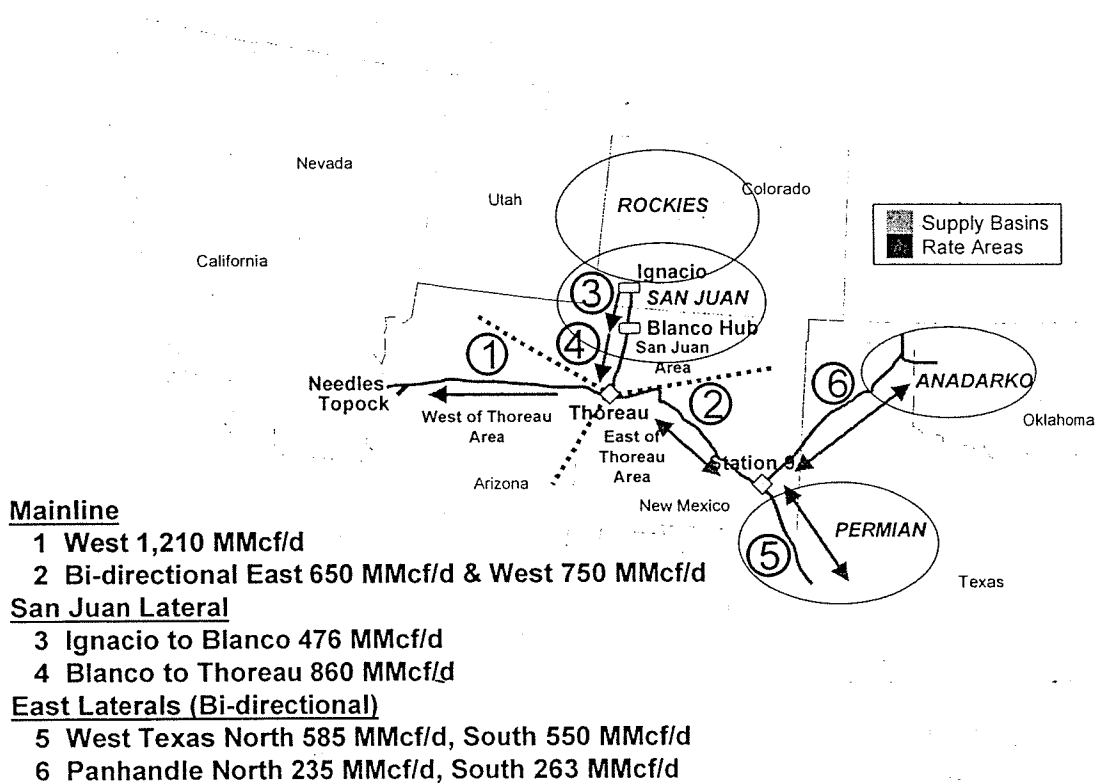
## **II. TRANSWESTERN'S INTERSTATE PIPELINE SYSTEM**

The Transwestern interstate natural gas pipeline system extends approximately 2,600 miles from west Texas, Oklahoma, New Mexico and southern Colorado to California and several southwest markets. (Please see the map of Transwestern's system at the end of this section.) The original Transwestern pipeline was constructed in 1960 to deliver natural gas to SoCalGas. Through various expansions, capacity on Transwestern's pipeline has grown from 350 million cubic feet per day ("MMcf/d") to 1,210 MMcf/d of capacity on the western portion of Transwestern's system and approximately 800 MMcf/d on the eastern portion.

Transwestern's bi-directional system can flow gas from supply basins either west to California or east to Texas interstate/intrastate pipeline markets. Transwestern has access to four significant supply basins: (1) the San Juan Basin in northwestern New Mexico and southern Colorado; (2) the Permian basin in western Texas and eastern New Mexico; (3) the Anadarko basin in the Texas and Oklahoma Panhandles; and (4) through Transwestern's pipeline interconnections, the Rocky Mountain basin. Transwestern's multiple supply sources combined with its bi-directional flow capability allow supplies to seek the market of choice, be it California, Arizona, the Texas intrastate markets or Mid-Continent markets.

**Figure 1**

**Map of Transwestern's Pipeline System**



### III. INTERSTATE CAPACITY FOR CORE CUSTOMERS

#### A. The Commission Should Adopt PG&E's Proposed 1-in-10 Year Planning Standards for the Sempra Utilities.

PG&E proposes jointly using 1-in-10 year peak-day and 1-in-10 year cold winter forecasts of core loads to adequately plan for core storage and transmission holdings.<sup>3</sup> Transwestern supports PG&E's proposal and recommends that the Commission adopt PG&E's proposed planning criteria for the Sempra Utilities as well.

PG&E notes that its proposed planning standards are both more consistent with the core reliability standards of other utilities and the risk preferences of core customers than the current 1-in-3 year peak day standard. PG&E also states that such standards would "reduce core customer exposure to extreme price volatility that often occurs during peak events, while significantly lowering the probability of noncore curtailments."<sup>4</sup>

Transwestern concurs with these observations.

The Sempra Utilities propose to meet the demand of their core customers by acquiring firm interstate transportation capacity rights to match 80-110% of core customers' average annual daily demand during non-winter months and 90-110% of this average during winter months.<sup>5</sup> In support of their proposal, the Sempra Utilities note that 108% of average temperature year daily demand is equivalent to the core procurement portfolio's cold temperature year demand forecast. Neither utility addresses the adequacy of these holdings for peak days, however, nor do they address the use of storage holdings to supply peak and cold-winter core loads.

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<sup>3</sup> Phase I Proposals and Data Response of Respondent Pacific Gas and Electric Company ("PG&E Proposals"), pp. 2-4.

<sup>4</sup>*Id.*, p.3

<sup>5</sup> SDG&E and SoCalGas Proposals, p. 40.

SoCalGas also notes that its proposed procurement standard is consistent with the applicable terms of the Settlement Agreement approved by the Commission in D.02-06-023. The Settlement Agreement extended SoCalGas' Gas Cost Incentive Mechanism ("GCIM"), which specifies formulas pertaining to procurement standards and shareholder reward levels for core supply acquisitions. However, the GCIM procurement standards appear, understandably, to be focused more on procurement costs than on supply reliability.<sup>6</sup>

The importance of peak day planning is illustrated by looking at SoCalGas' forecast for core gas loads in 2005, as shown in the 2002 California Gas Report. After accounting for firm withdrawal requirements, this forecast shows required flowing supplies about forty percent greater (or about 400 MMcf/d) than the average annual requirements proposed by SoCalGas (when compared on a daily basis).<sup>7</sup> In D.02-07-037 (OIR to Preserve Interstate Capacity to California), the Commission noted the importance of obtaining interstate capacity for a peak day as opposed to planning for average annual demands:

Yearly demand totals provide little assistance in ascertaining whether SoCalGas' customers' needs during peak summer or winter months can be met if California is deprived of up to 725 MMcf/d of El Paso capacity. The potential for exorbitant prices, blackouts, or natural gas curtailments would, in all likelihood, occur during peak times rather than on a yearly basis.<sup>8</sup>

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<sup>6</sup> See D.02-06-033, p. 6 ("The GCIM is structured to provide an incentive for SoCalGas to invest in its Gas Acquisition Department and make sound gas purchasing decisions").

<sup>7</sup> 2002 California Gas Report, page 63 (compared with the annual core demand provided by the SoCalGas' response to the Commission data request question 1 in this proceeding).

<sup>8</sup> D.02-07-037, p.8.

A procurement standard based on a combination of peak day and cold winter analysis would help to insure that interstate capacity and supplies will be available to utilize the 15-20% slack intrastate capacity generally recommended for the California utilities when this capacity is needed. The danger of not securing adequate interstate capacity is that access to interstate supplies may be lost to markets outside of California.

It is also important that planning criteria be consistent for all of the major utilities. If the Sempra Utilities have planning standards that are less stringent than those adopted by PG&E, then PG&E's customers would end up subsidizing the costs of ensuring reliable supplies to the benefit of the customers of the other utilities.

For all of these reasons, Transwestern recommends that the Commission order the Sempra Utilities to utilize the planning criteria proposed by PG&E. In addition, Transwestern recommends that the Commission adopt the following proposed Findings of Fact:

- (1) The 1-in-10 year peak day and cold-winter planning criteria for interstate capacity commitments proposed by PG&E will reduce core customer exposure to extreme price volatility that often occurs during peak events, while significantly lowering the probability of noncore curtailments.
- (2) The planning criteria proposed by SoCalGas and SDG&E may not be adequate to protect core customers from extreme price volatility during peak events, and may result in noncore curtailments.
- (3) In order to prevent PG&E's core customers from subsidizing the reliability of service to the core customers of SoCalGas and SDG&E, all three utilities should utilize consistent planning criteria for core capacity commitments.

#### **B. Only Firm Capacity Can Provide "Reliability Insurance."**

By releasing interstate capacity and holding less than the capacity needed for a peak day, SoCalGas implies that the interstate pipeline capacity to which it currently holds firm rights, if "turned back" by the utility, will be available to serve core demand

when peak demands arise, as well as when core loads grow. That is not a realistic assumption, however. As noted in the OIR, “one of the recent developments [that] seriously threaten California’s supply of natural gas in the long-term ... is the potential loss of interstate capacity dedicated to California” due to the growing natural gas demands in neighboring regions.<sup>9</sup> Indeed, recent experience with “turned back” capacity on the interstate pipeline system of El Paso Natural Gas Company (“El Paso”) demonstrates that the risk that interstate capacity that is currently available to California markets could be lost to other markets in the future is real and significant.

Moreover, the California Energy Commission (“CEC”) recently noted in its *Natural Gas Market Assessment* that electricity generators in Arizona will seek the low-priced gas in the San Juan basin via the El Paso (northern), Transwestern and Southern Trails pipeline systems.<sup>10</sup> The CEC report also projects gas loads, largely driven by increases in gas-fired generation, will grow more rapidly in areas outside of California within the Western States region.<sup>11</sup> Recent CEC projections concerning generation additions in Arizona and New Mexico indicate that such additions could add 100-200 MMcf/d of gas loads between now and 2007.<sup>12</sup> These factors make reliance on the recall of relinquished interstate capacity a very risky proposition.

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<sup>9</sup> OIR, p.5

<sup>10</sup> California Energy Commission, *Natural Gas Market Assessment*, Staff Report August 2003, #100-03-006, p.31

<sup>11</sup> *Id.*, p.17.

<sup>12</sup> Sources:

- Plant location, size and status: “Proposed Generation Within the Western Systems Coordinating Council”, CEC Database, Updated February 5, 2004.  
[http://www.energy.ca.gov/electricity/wscg\\_proposed\\_generation.html](http://www.energy.ca.gov/electricity/wscg_proposed_generation.html)
- Heat rate and capacity factor: CEC Comparative Cost of New Generating Resource Technologies, August 2003. [http://www.energy.ca.gov/reports/2003-08-08\\_100-03-001.PDF](http://www.energy.ca.gov/reports/2003-08-08_100-03-001.PDF)

The total design capacity of East of California delivery points on the Transwestern's mainline west system today is 436,250 Mcf/d, which equates to 36% of the 1.2 Bcf/d of capacity on Transwestern's mainline west system. Transwestern currently has the capability of re-directing this capacity to certain Arizona markets. Additionally, Transwestern continues to evaluate the economic feasibility of building a 500,000 Mcf/d lateral to serve the Phoenix market. Such lateral would allow the existing East of California mainline capacity to be used to reach the Phoenix market. A more detailed description of the Phoenix project are set forth in Transwestern's comments in the Arizona Corporation Commission's February 13, 2003 workshop in the Natural Gas Infrastructure proceedings.<sup>13</sup>

If Transwestern's San Juan capacity is not contracted to deliver to the California or other mainline west markets, it will be contracted to deliver to Texas intrastate and Mid-continent interstate markets delivering off the East-end of Transwestern's system. Shippers can transport up to 650,000 of San Juan gas to markets on the east end of the system. (See Figure 1.) California's opportunity to access that portion of competitively priced San Juan Basin supplies could be lost for the term of the agreements. (Note that the average contract life of Transwestern's San Juan firm agreements has been eight years.)

Thus, as the OIR observes, there is legitimate concern that "unless interstate pipeline capacity is under a contract for firm service to California primary delivery points and the contracting shipper intends to use the capacity to transport natural gas to California, there is no assurance that the pipeline capacity will be available to meet

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<sup>13</sup> Transwestern's comments are posted online at <http://www.cc.state.az.us/utility/gas/NOI-TP.pps>.

California's needs.”<sup>14</sup> Accordingly, the only capacity that the Commission can be sure will be available to serve core customers in the future is firm capacity held by the utilities.

**C. The Utilities Should Be Required to Maintain Adequate Access to All Major Producing Basins.**

Transwestern understands that the California utilities seek a diversified portfolio of interstate capacity to further enhance the reliability of supplies.<sup>15</sup> Transwestern agrees with this policy. Such diversity will best maintain supply reliability in the event of temporary constraints or outages on interstate capacity, and as gas flows change the price and availability of gas to California markets. Acquiring a diverse mix of interstate capacity also has benefits in terms of commodity costs given the uncertainty inherent in regional gas prices. It is important, however, that the utilities not sacrifice long-term supply reliability in the pursuit of supply diversity.

**1. Diversity goals should recognize price uncertainty.**

In planning for the future the Commission should recognize the uncertainty inherent in forecasts of natural gas prices, consumption and production. For instance, it would be imprudent to assume that Rocky Mountain supplies will be less expensive than other interstate supplies and to make long-term procurement portfolio choices based on this assumption.

In its annual analysis of forecast accuracy, the Energy Information Administration (“EIA”) noted, “Natural gas generally has been the fuel with the least accurate forecasts

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<sup>14</sup> OIR, pp. 15-16.

<sup>15</sup> See, e.g., SoCalGas/SDG&E Proposals, pp. 27 and 41.

in consumption, production, and prices.”<sup>16</sup> EIA observed that in past decades, the impacts of competition, technological improvement, and the preference for natural gas due to environmental pressures have been hard to predict. For example, regarding U.S. natural gas consumption for 2002, the accuracy of EIA’s forecasts for the past five years have ranged between 0.5% below to 6% above the actual consumption. Concerning natural gas production in the lower forty-eight states in 2002, EIA’s forecasts for the past five years have ranged between 2.5% below to 6.5% above actual production. Regarding price, EIA’s forecasts for the past five years for 2002 were below the actual price by between 1% and 32%.

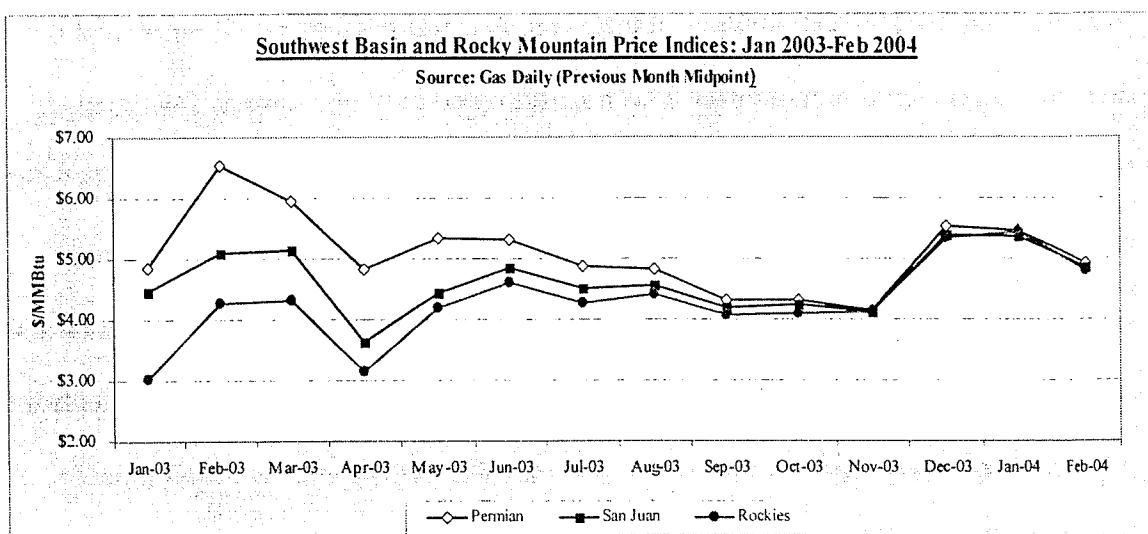
The difficulty in projecting even average U.S. wellhead prices should especially be noted, much less determining the likely price differential among producing areas. For example, the CEC has recently been utilizing price forecasts that assume that the difference in price between the Rocky Mountain, San Juan and Permian Basins will grow in the future with Rocky Mountain gas increasingly becoming the least expensive supply.<sup>17</sup> As shown in Figure 2, however, gas prices of the three basins have actually converged in the last two years since the removal of transmission constraints at the basin (via the Kern River Expansion) to Rocky Mountain gas. This trend suggests that the price of Rocky Mountain gas will rise to the prevailing market price rather than remaining at a lower level.

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<sup>16</sup> [http://www.eia.doe.gov/oiaf/analysispaper/forecast\\_eval.html](http://www.eia.doe.gov/oiaf/analysispaper/forecast_eval.html)

<sup>17</sup> Electric and Natural Gas Assessment Report, Draft Staff Report, August 2003, p.90

**Figure 2**



## 2. Forecasts concerning LNG supplies are highly variable.

Regarding forecasts for 2015, the EIA has compiled a comparison of projections of the natural gas wellhead prices, production (lower forty-eight states), consumption, and LNG usage (see Appendix A).<sup>18</sup> Within a group of eight forecasts from various sources, projections for domestic dry gas production in 2015 ranged from 17.9 to 21.2 trillion cubic feet, projections for consumption ranged from 26.7 to 31.1 trillion cubic feet and LNG usage ranged from 2.5 to 4.75 trillion cubic feet. The wide range of these projections illustrates the difficulty in predicting the future balance of natural gas demands and supplies and the need for LNG supplies. Further, given the recent cancellation of the Marathon and Calpine LNG projects, it may be prudent to carefully consider the viability of the competing LNG projects before investing in supporting infrastructure.

<sup>18</sup> Energy Information Administration, Annual energy Outlook 2004 with Projections to 2025, Table 31.

Indeed, California previously reacted to erroneous forecasts of dramatic declines in southwest production and their supposed imminent decline to justify a need for LNG supplies. In the early to mid-1970s, natural gas production in the southwest was declining such that plans were made to use the El Paso pipeline to send oil east. California's Canadian supplies were also thought to be at risk due to the expectation that Canada would curtail exports to the U.S. to ensure adequate supplies for the domestic Canadian market. In response to these forecast declines in southwest and Canadian natural gas supplies, plans for the use of LNG gas were made. Specifically, LNG terminals were planned for Los Angeles harbor, Oxnard and at Point Conception. Alaskan or Indonesian gas supplies would be liquefied and sent to these terminals, displacing gas from New Mexico and Texas. It was expected that the remaining southwestern gas production would be sent to eastern markets.<sup>19</sup> Like many projections, the imminent need to displace Southwest and Canadian gas with LNG and Alaskan supplies twenty-five years ago proved dramatically inaccurate.

**3. There are opportunities for increased San Juan supplies to reach the California market in the future.**

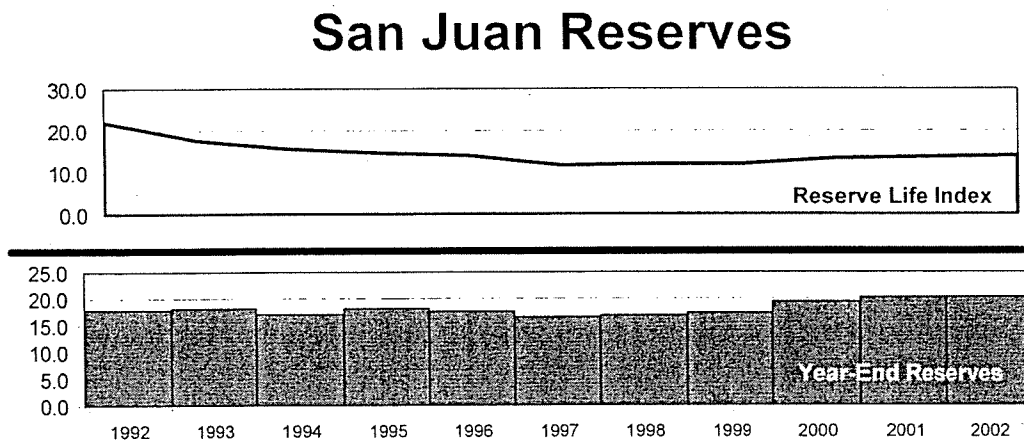
Similarly, in the late Eighties many analysts believed Southwest production had begun to decline and that California required additional pipeline capacity to Canada and to the Rocky Mountains. Instead, these Canadian and Rocky Mountain supplies had to compete with substantially enhanced production from the San Juan basin that resulted from the successful development of its coal seam resources.

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<sup>19</sup> Ahern, William and R. Doctor, W. Harris, A. Lipson, D. Morris, R. Nehring. *Energy Alternatives for California: Paths to the Future – Executive Summary*. The Rand Corporation, R-1793-CSA/RF, December 1975.

The San Juan basin also continues to be a robust supply source, as overall reserves in the basin have increased to approximately 20.3 trillion cubic feet (“Tcf”) with a reserve life of nearly 15 years. Figure 3 shows the year-end proved reserves and reserve life for the San Juan basin since 1992. Although the reserve life fell in 1992, after the initial Transwestern San Juan expansion allowed additional production to be exported from the basin, the reserve life has grown in recent years. Moreover, in April 2003, the U.S. Geological Service more than doubled the estimate of total San Juan reserves, including unproven reserves, to 50 Tcf. With enhancements in technology, higher gas prices and revised New Mexico well spacing rules, factors are in place to grow proven reserves further.

Figure 3

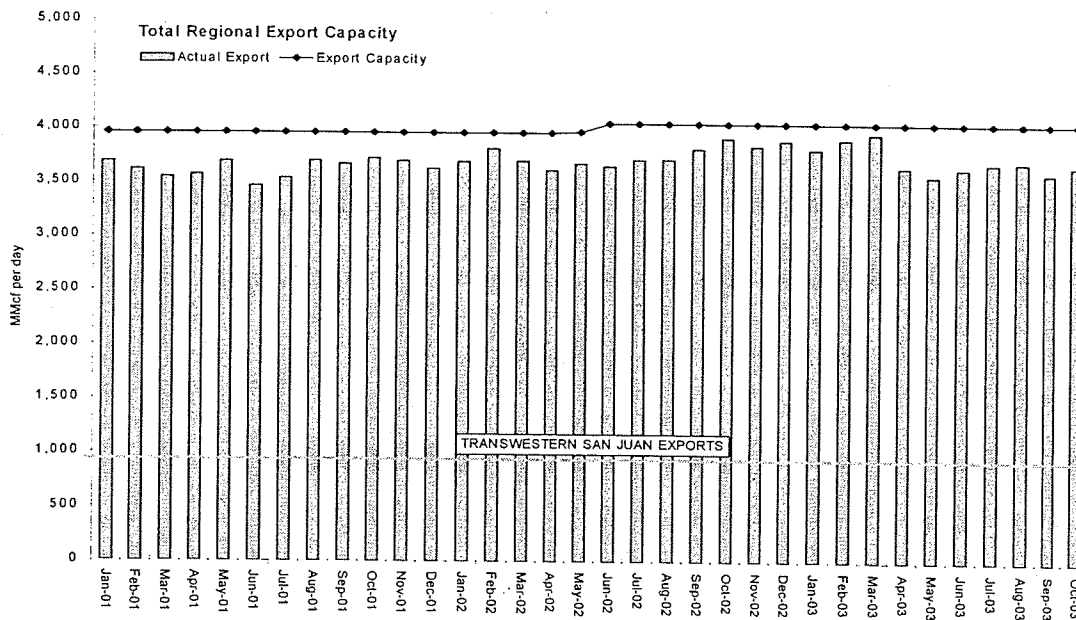


Source: Lippman Consulting

Although the San Juan basin has not seen an increase in production in the period 2001-2004 in response to higher prices, Transwestern believes that this delay has been the result of pipeline constraint from the basin. As shown in Figure 4, there is currently no available capacity to carry any additional gas out of the San Juan basin. As previously noted, however, Transwestern is currently working on a project to increase the San Juan

lateral capacity by an additional 375,000 MMcf/d. On September 3, 2003, Transwestern filed a request that the Federal Energy Regulatory Commission (“FERC”) staff commence a National Environmental Policy Act (“NEPA”) pre-filing review for the planned San Juan 2005 Expansion Project. Transwestern’s request was approved on September 17, 2003, and the project was assigned Docket No. PF03-8-000. Transwestern expects to file a FERC certificate in April 2004 and anticipates an in-service date in the second quarter of 2005. The project is supported by San Juan producers seeking to remove the current basin constraint and provide opportunity for additional San Juan supplies to flow in the Transwestern mainline.

**Figure 4**

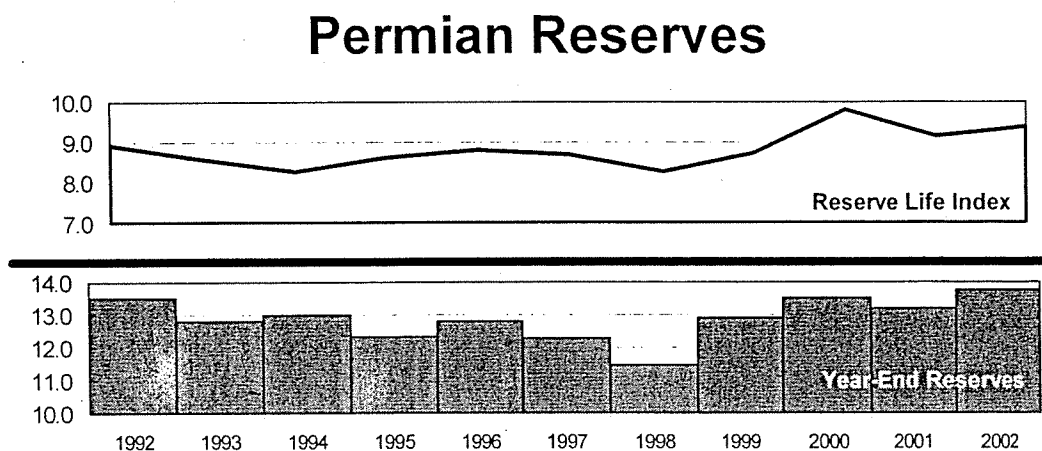


Source: Lippman Consulting, Inc.

#### 4. The Permian Basin remains an important part of a secure gas future for California.

The Permian basin continues to be an important source of gas supply. As shown in Figure 5, reserves in the Permian basin of 13.7 Tcf at year-end 2002 are slightly above 1992 levels, and the reserve life has grown over this same period. Clearly, the Permian basin has not been the cheapest source of supply to California in 2003 or 2004, and it is therefore understandable that California utilities seek to decrease their Permian access based on contemporary economics. The Commission should consider whether this strategy best serves California ratepayers in the long run. One need only look back to as recently as 2001 to see Permian supplies have played a critical part in meeting California gas demand. In 2001, average deliveries on the Transwestern mainline west were approximately 1 Bcf/day, meaning that over 200,000 MMcf/day were flowing from Permian basin areas. Moreover, shippers on the Transwestern system contracted for in 2001, and Transwestern placed in service in 2002, a \$70 million, 120,000 MMcf/day expansion of Transwestern's mainline sourced solely from the Permian basin.<sup>20</sup>

Figure 5



Source: Lippman Consulting

Since 2002 Permian basin prices have been driven up by demand from weather sensitive mid-continent and eastern US markets, making them less attractive to California markets at a time where lessened market demand allowed customers the opportunity to be selective in their gas supply choices. One should not assume, however, that Permian supplies will not become necessary or attractive in the future, just as they were needed in 2000-2001. To the extent projects are completed to carry Rockies gas to mid-continent markets or additional Gulf Coast LNG terminal capacity is added, Permian prices may fall, thereby allowing these supplies to once again economically reach California markets. Thus, Transwestern believes it would be shortsighted to ignore the importance of the Permian basin in a supply portfolio.

Moreover, the cost of maintaining access to the Permian basin is small in comparison to the flexibility it provides to utilities. As SoCalGas has observed, the cost of interstate capacity is a small fraction of the total cost of gas from the traditional supply basins: "The cost of holding interstate capacity has not been, nor is it expected to be, a dominant component of the total delivered cost of gas for SoCalGas' core procurement customers."<sup>21</sup> Indeed, the cost of interstate capacity is truly insignificant when compared to the potential costs that the utilities would incur for spot supplies during times of shortage or supply interruption. For example, the cost of holding 100 MMcf/d of capacity on Transwestern's pipeline from the Permian basin would be about twenty cents per month for the average residential customer. Thus, when it comes to system

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<sup>20</sup> See Transwestern's comments in the Arizona Corporation Commission's February 13, 2003 workshop in the Natural Gas Infrastructure proceedings, *supra* note 13.

<sup>21</sup> SoCalGas/SDG&E Proposals, p.21.

reliability, the old adage that one should avoid being “penny wise and pound foolish” truly applies.

#### **4. Overall Supply Diversity Approach.**

In light of the foregoing, Transwestern recommends that the utilities be required to ensure supply diversity by maintaining adequate firm access rights to *all* of the major supply basins, with that policy being stated in the following proposed Finding of Fact:

Supply diversity can only be assured by the utilities maintaining firm access to all the major supply basins.

In addition, Transwestern recommends that, consistent with the requirement to maintain firm access to all major supply basins, SoCalGas’ proposed Findings of Fact concerning its Transwestern and El Paso contracts, which provide firm access to the San Juan and Permian basins, be modified as follows:

- (4) SoCalGas’ request for authorization to renegotiate ~~reduced~~ amounts of capacity for core procurement customers on the El Paso and Transwestern pipelines is reasonable and in the public interest.
- (5) In the event that SoCalGas is unable to renegotiate ~~reduced~~ amounts of capacity under satisfactory terms on Transwestern and/or El Paso, SoCalGas’ request for authorization to terminate expired transportation capacity on Transwestern and/or El Paso and to exercise ROFR to acquire ~~reduced~~ amounts of capacity on Transwestern and/or El Paso and to acquire transportation capacity on other pipelines to meet core needs is reasonable and in the public interest.
- (6) SoCalGas’ request for authorization to renegotiate ~~reduced~~ amounts of capacity and to terminate contracts with El Paso and Transwestern is consistent with the goal of achieving a more diversified portfolio and the intent of D.02-07-037 because SoCalGas does not intend to ~~significantly~~ reduce firm interstate pipeline holdings held on behalf of core procurement customers, but rather will diversify those holdings.

#### **IV. ACCESS FOR LIQUEFIED NATURAL GAS SUPPLIES**

Transwestern submits that ratepayers stand to derive the most benefit from potential new supplies, including LNG supplies, if and only if the providers of those supplies are required to compete with existing supplies on an even playing field. Consistent with the Commission's "let the market decide" policy and preference for marginal cost pricing, the sponsors of a LNG project should be required to pay the costs of any expansions to a utility's backbone transmission that are necessary to accommodate deliveries from the project without displacing pre-existing supplies. The costs of expensive LNG supply projects should not be "rolled in" with other transmission costs; rather, each and every project should be subject to competition.

#### **V. FIRM TRADABLE ACCESS RIGHTS**

Transwestern and its shippers have made investments in infrastructure, based on, among other things, the existence of sufficient take-away capacity. The firm point capacity at Transwestern's largest California delivery point, SoCalGas North Needles is 800,000 MMcf/day and is fully contracted. Nevertheless, Transwestern understands that the historical grandfathered approach to assigning point rights does not fit with SoCalGas' desire to promote supply diversity and gas on gas competition in the future and accordingly Transwestern supports SoCalGas' proposal to establish a system of firm tradable rights for receipt point capacity as well as establishing the North Desert receipt points as a Transmission Zone. Transwestern agrees that owners of backbone transmission take-away capacity on the SoCalGas system need the ability to "establish a firm, reliable connection between a particular supply source and the customer's burner-

tip”<sup>22</sup> As SoCalGas notes in its response, under current rules, the mismatch between primary upstream and downstream rights makes it difficult to create a firm connection between a supplier and an end-use customer that is reliable every day of the year.<sup>23</sup>

Transwestern believes, however, that the customers’ ability to take advantage of this diversity and competition would be hindered by the three-year open season cycle that SoCalGas’ proposes. If customers are not allowed, following the initial Open Season, to access multiple receipt points on a primary basis through a pooling mechanism and/or to amend their primary firm receipt points, subject to available capacity, within their Transmission Zone at any time upon request, supply diversity will be frustrated. Moreover, it means that any price forecasts or biases that exist at the time of the initial Open Season will be cast into stone.

In contrast, Transwestern allows shippers within an operational area to amend primary receipt or delivery points on a daily basis, with as little as one hour notice prior to scheduling. Shippers can request changes for a single day, a specific term or for the remainder of the contract. This allows shippers to adjust their receipt points to match up with their supplies without losing priority of service. Requests are handled electronically, provide minimal transactional burden and insure that contract rights are maintained on an accurate and up to the minute basis.

Pooling provides a different means of giving shippers flexibility to match supply and capacity without sacrificing service priority. Pools allow shippers to nominate from any of a group of points within a pool without sacrificing the priority of service.

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<sup>22</sup> SoCalGas/SDG&E Proposals, p. 100.

<sup>23</sup> *Id.*, p. 99.

SoCalGas has proposed to establish a North Desert Transmission Zone. SoCalGas could also create a North Desert Pool Point representing the corresponding North Desert receipt interconnects. This would allow SoCalGas shippers to choose between supply basins on an ongoing basis without jeopardizing the reliability of their firm access rights. PG&E has been successful in offering its customers flexible primary receipt point access through pooling on its system. Transwestern has also established supply pools. For example, SoCalGas has the West Texas Pool as a primary receipt point on its Transwestern mainline contract from the Permian basin. This allows SoCalGas to change their supply sources on Transwestern's West Texas lateral monthly, daily or even within the gas day, if desired, without amending their contract receipt point.

Alternate receipt point access and other options afforded through the secondary market offer some relief for customers locked-in to certain receipt points for three years, but fall short of allowing customers to fully enjoy supply diversity by allowing them to amend their primary receipt points as numerous variables change over time. Alternate receipt point access, due to its secondary scheduling priority, does not supply the certainty from supply source to burner-tip heralded by SoCalGas. Thus, customers have a strong preference for primary access rights.

In their response, SoCalGas proposes to allow capacity holders to "re-contract" any part of their capacity from any receipt point on the system to a different point to the extent capacity is available at the requested receipt point and within the respective Transmission Zone. Transwestern requests clarification that this ability would continue on a regular basis, at the customer's request, and that amended receipt point rights would be on a primary basis.

## VI. CONCLUSION

For the foregoing reasons, Transwestern recommends that the Commission take the following actions in Phase I of this proceeding:

- (1) Adopt the regulatory approval process proposed by the Sempra Utilities for new interstate capacity commitments to meet core supply obligations;
- (2) Require the Sempra Utilities to utilize the planning criteria for core capacity commitments proposed by PG&E;
- (3) Require SoCalGas, SDG&E, and PG&E to maintain adequate access to *all* of the major gas supply basins.
- (4) Reject SoCalGas' proposal to automatically "roll in" the costs of expanding its backbone transmission system to accommodate LNG and other new supplies.
- (5) Adopt SoCalGas' proposal to establish a system of firm tradable rights for receipt point capacity, with the modification that customers be allowed to assign or to amend their primary firm receipt points, subject to available capacity, at any time upon request after the initial open season.

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In addition, Transwestern requests that the Commission adopt the proposed Findings of Fact and the modifications to SoCalGas' proposed Findings of Fact set forth in Section III.A and Section III.C.4 above.

Respectfully submitted,

TRANSWESTERN PIPELINE COMPANY

By: \_\_\_\_\_

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March 23, 2004

# Appendix A

## **CERTIFICATE OF SERVICE**

I hereby certify that I have this day served a copy of the foregoing document on all parties of record in the above captioned proceedings by serving an electronic copy on their email addresses of record and by mailing a properly addressed copy by first-class mail with postage prepaid to each party for whom an email address is unavailable.

Executed on March 23, 2004, at Woodland Hills, California.

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Michelle Dangott



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY  
REGION IX

75 Hawthorne Street  
San Francisco, CA 94105

March 31, 2004

Commander Mark Prescott  
U.S. Coast Guard  
ATTN: Docket Management Facility  
U.S. Department of Transportation  
Room PL-401, 400 Seventh Street, SW.  
Washington, DC 20590

Subject: Notice of Intent to Prepare Draft Environmental Impact Statement/Report,  
Cabrillo Port Liquefied Natural Gas Deepwater Port offshore Ventura County, California

Dear Commander Prescott:

The U.S. Environmental Protection Agency (EPA) has reviewed the Notice of Intent (NOI) to prepare a Draft Environmental Impact Statement/Report (DEIS/R) for the above-referenced project. Our comments are provided under the National Environmental Policy Act (NEPA), the Council on Environmental Quality's NEPA Implementing Regulations (40 CFR Parts 1500-1508), and Section 309 of the Clean Air Act (CAA). EPA previously provided comments on September 23, 2003 for the project's pre-application licensing materials (enclosed) and met with the Coast Guard on September 24, 2003. EPA's detailed scoping comments are also enclosed.

The DEIS/R will assess potential environmental effects associated with construction and operation of a proposed liquefied natural gas (LNG) deepwater port (DWP) in Federal waters 14 miles offshore Ventura County, California. The DEIS/R is being prepared to meet the requirements of both NEPA and the California Environmental Quality Act (CEQA). The Coast Guard is the lead Federal agency for NEPA and the Maritime Administration is co-lead agency. The California State Lands Commission (SLC) is the lead CEQA agency.

EPA is a "Participating Agency" pursuant to a recently-signed Memorandum of Understanding Related to the Licensing of Deepwater Ports. EPA is also a "Cooperating Agency" pursuant to 40 CFR 1501.6 since we have authority under the Clean Air Act and the Deepwater Port Act for issuing Preconstruction and Operating Air Permits, and a Clean Water Act National Pollutant Discharge Elimination System (NPDES) Permit. This NPDES Permit is for a facility that is considered a "new source" under the Deepwater Port Act [33 USC 1502(9)] and thus also requires EPA's compliance with NEPA. Therefore, we request the opportunity to review and

on interim and draft NEPA documents to ensure that the EPA's NEPA regulations (at 40 CFR Part 6) are met concurrently with the Coast Guard's NEPA process.

We appreciate the opportunity to provide comments. Please send one paper copy and five CD-ROM copies of all interim and draft NEPA documents to me at the letterhead address (mail code: CMD-2). Please send five paper copies of the Draft EIS to me at the letterhead address when it is released for public review. If you have any questions, please call me at 415-972-3854 or my staff reviewer, David Tomsovic, at 415-972-3858 or at < [Tomsovic.David@epa.gov](mailto:Tomsovic.David@epa.gov) >.

Sincerely,

A handwritten signature in black ink, appearing to read "Lisa B. Hanf", written in a cursive style.

Lisa B. Hanf, Manager  
Federal Activities Office

Enclosures: 2  
EPA's Detailed Scoping Comments  
EPA's September 23, 2003 letter to Coast Guard

cc: Ken Mittelholtz, Office of Federal Activities, EPA, Washington, D.C.  
Keith Lesnick, Maritime Administration, Washington, D.C.  
Cy Oggins, California State Lands Commission, Sacramento, CA

### **Water Quality**

Several potential discharges can be expected from the proposed project's construction and operation including runoff from onshore construction, sanitary and domestic wastes, facility cooling water, platform runoff, hydrostatic test water, firefighting water, drill cuttings and drilling muds, ballast water, "black water," and use of chemicals; and possibly diesel generators' cooling water and discharges from making potable water. The NOI does not identify these discharges or whether the DEIS/R will evaluate their environmental effects. For each fully evaluated alternative, the DEIS/R should identify all reasonably foreseeable discharges expected from the proposed project's construction and operation, and evaluate the potential direct, indirect, and cumulative effects on water quality and biological resources (aquatic and terrestrial). For onshore and offshore discharges, consistency with applicable requirements, including maintaining State-adopted, EPA-approved water quality standards, should be addressed (e.g., temperature, turbidity, metals, toxic pollutants, and total dissolved solids). Mitigation to protect onshore and offshore water quality during the project's construction and operation should be evaluated.

### **Air Quality**

The DEIS/R should provide an analysis of applicable air quality standards, ambient conditions, and potential air quality impacts (offshore and onshore) for each fully evaluated alternative. Cumulative and indirect air quality impacts should also be evaluated.

\* The DEIS/R should address the applicability of Clean Air Act (CAA) Section 176 and EPA's general conformity regulations at 40 CFR Parts 51 and 93. Federal agencies need to ensure that their actions, including construction emissions subject to state jurisdiction, conform to an approved implementation plan. Emissions authorized by a CAA permit issued by EPA or the air pollution control district(s) would not be assessed under general conformity but through the permitting process.

The NOI identifies issues to be addressed, including "Air Quality: Impacts on regional air quality, visibility and other resources in sensitive Federal Class I areas (e.g., Channel Islands National Park)." CAA Section 162 has criteria for mandatory Class I areas, including national parks in existence as of August 7, 1977 exceeding 6,000 acres [CAA 162(a)(4); 42 U.S.C. § 7472(a)(4)]. The list of mandatory Class I areas in California is at 40 CFR Part 81.405. Channel Islands National Park is not listed as a mandatory Class I area, nor is EPA aware of any proposal designating it as such. The DEIS/R should reflect this.

## Mitigation for Reducing Onshore Construction Emissions

EPA recommends an evaluation of the following measures to reduce onshore construction emissions of criteria air pollutants and hazardous air pollutants (air toxics):

- Reducing emissions of diesel particulate matter (DPM) and other air pollutants by using particle traps and other technological or operational methods. Control technologies such as traps control approximately 80 percent of DPM. Specialized catalytic converters (oxidation catalysts) control approximately 20 percent of DPM, 40 percent of carbon monoxide emissions, and 50 percent of hydrocarbon emissions.
- Ensuring that diesel-powered construction equipment is properly tuned and maintained, and shut off when not in direct use.
- Prohibiting engine tampering to increase horsepower.
- Locating diesel engines, motors, and equipment as far as possible from residential areas and sensitive receptors (schools, daycare centers, and hospitals).
- Requiring low sulfur diesel fuel (<15 parts per million), if available.
- Reducing construction-related trips of workers and equipment, including trucks.
- Leasing or buying newer, cleaner equipment (1996 or newer model), using a minimum of 75 percent of the equipment's total horsepower.
- Using engine types such as electric, liquified gas, hydrogen fuel cells, and/or alternative diesel formulations.
- Adopting a "*Construction Emissions Mitigation Plan*" to reduce construction emissions.
- Working with the local air pollution control district(s) to implement the strongest mitigation for reducing onshore construction emissions.

Including construction-related air mitigation for major Federal actions serves as a model for State and local agencies, especially in nonattainment or maintenance areas. The National Aeronautics and Space Administration (NASA) recently adopted a number of such measures in a Record of Decision for the *NASA Ames Development Plan, Santa Clara County, California*. The Federal Aviation Administration also included similar measures in a Draft Supplemental EIS for *Los Angeles International Airport Master Plan Improvements*.

## Purpose and Need/Reasonable Alternatives

Although the NOI does not identify the project's intended purpose and need, it appears that one objective is to "distribute natural gas throughout the Southern California region." The DEIS/R should clearly identify the stated purpose and need since it provides the basis for identifying a reasonable range of alternatives.

A rigorous alternatives analysis is particularly important if the proposed project needs an individual permit pursuant to Clean Water Act (CWA) Section 404. The NOI states that the DEIS/R will consider a location in the vicinity of the proposed project, and other locations adjacent to the California coast; specifically, alternate locations near Santa Barbara Channel and Anacapa Island. We understand that land-based alternatives will be examined, including sites at

\*

Point Conception and Camp Pendleton. Alternate technologies (including open-rack vaporizers and alternative floating facility designs) and alternate pipeline routes will also be evaluated.

We note that the Interim Final EIS (p. 2-2) for the Louisiana Port Pelican facility stated, "Alternatives for a natural gas deepwater port may extend to matters such as its specific location, *methods of construction* and *platform layout*, and *technologies* for storing and regasifying LNG." (italics added). To the extent that the Louisiana Port Pelican or other Coast Guard NEPA documents for DWP LNG facilities evaluated alternatives that should be considered in the Cabrillo DEIS/R, especially if adverse environmental impacts are avoided or reduced, we recommend doing so.

### **Hazardous Materials and Hazardous Waste**

The NOI states that an impact requiring analysis is "Hazardous Materials (HAZMAT): Impacts from HAZMAT spills including petroleum, LNG, hydrocarbons, fuels, lubricant, urea, paints, solvents, and sanitary waste." EPA encourages an analysis of the direct, indirect, and cumulative impacts from hazardous materials use and potential releases of hazardous materials. We also recommend evaluating reasonable mitigation to avoid or reduce impacts from using hazardous materials during construction and operation.

In addition to hazardous materials, the DEIS/R should address potential impacts of hazardous waste from construction and operation. The DEIS/R should identify projected hazardous waste types and volumes, and expected storage, disposal, and management plans. The DEIS should address the applicability of State and Federal hazardous waste requirements. Appropriate mitigation should be evaluated, including measures to minimize the generation of hazardous waste (i.e., hazardous waste minimization). Alternate industrial processes using less toxic materials should be evaluated as mitigation. This potentially reduces the volume or toxicity of hazardous materials requiring management and disposal as hazardous waste.

### **Mitigation and Pollution Prevention**

The DEIS/R should evaluate the feasibility of adopting mitigation to avoid, reduce or compensate for adverse environmental impacts from construction and operation. NEPA does not require that an impact be "significant" before mitigation can be presented in an EIS.

"All relevant, reasonable mitigation measures that could improve the project are to be identified....Mitigation measures must be considered even for impacts that by themselves would not be considered 'significant.' Once the proposal itself is considered as a whole to have significant effects....mitigation measures must be developed where it is feasible to do so." (Council on Environmental Quality (CEQ), 1981, *Forty Most Asked Questions Concerning CEQ's National Environmental Policy Act Regulations*, 19a and 19b).

CEQ also issued guidance on integrating pollution prevention measures in NEPA documents (January 12, 1993 Memorandum to Heads of Federal Departments and Agencies Regarding Pollution Prevention and the National Environmental Policy Act). Many strategies can reduce pollution and protect resources, including using fewer toxic inputs, altering manufacturing and facility maintenance processes, and conserving energy. Consistent with CEQ's guidance, we recommend presenting all reasonable mitigation and pollution prevention measures.

### **Environmental Justice**

Consistent with Executive Order 12898, the DEIS/R should evaluate potential impacts to low-income or minority populations (e.g., onshore construction impacts), including disproportionately high and adverse impacts. The DEIS/R should address consistency with CEQ's guidance on "*Environmental Justice Under the National Environmental Policy Act*," which states that mitigation in EISs should reflect the needs and preferences of affected low-income and minority populations to the extent practicable. Pollution prevention measures such as air mitigation are important in reducing adverse effects on environmental justice populations (June 2003 report to EPA, "*Advancing Environmental Justice Through Pollution Prevention - A Report Developed from the National Environmental Justice Advisory Council Meeting, December 2002*," [www.epa.gov/compliance/resources/publications/ej/pollution-prevention-recom-report.html](http://www.epa.gov/compliance/resources/publications/ej/pollution-prevention-recom-report.html)).

### **Permits, Approvals, and Consultation**

A permit or authorization may be required from the Corps of Engineers under CWA Section 404 and 40 CFR Part 230. The DEIS/R should address the requirements of 40 CFR Part 230, and whether the project needs an individual Section 404 permit or qualifies for a general (nationwide) permit. If an individual permit is needed, the DEIS/R should address requirements such as identifying the least environmentally damaging practicable alternative; adequately mitigating unavoidable impacts to aquatic resources; and maintaining State-adopted, EPA-approved water quality standards.

The DEIS/R should address the applicability of the Marine Protection, Research, and Sanctuaries Act (MPRSA). Based on EPA Region 9's understanding of how the facility would be built, it does not appear that "material" would be transported to the ocean for purposes of "disposal." Thus, no MPRSA permit would be required from EPA.

The Louisiana Port Pelican EIS contained a useful table of applicable laws and Executive Orders. We recommend that the Cabrillo DEIS/R provide a similar table for construction and operation. Since the project needs permits or authorization from local (county) agencies for onshore activities, please include applicable local rules as well.



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY  
REGION IX  
75 Hawthorne Street  
San Francisco, CA 94105

September 23, 2003

Commander Mark Prescott, Acting Chief  
Office of Operating and Environmental Standards  
U.S. Coast Guard (code: G-MSO-2)  
Department of Homeland Security  
2100 2nd Street, S.W.  
Washington, D.C. 20593

Re: Cabrillo Port Application for Deepwater Port License and associated Environmental Analysis (August 2003), submitted by BHP Billiton for a proposed facility in the vicinity of Ventura, California.

Dear Commander Prescott:

EPA received BHP Billiton's (BHP) Deepwater Port License (DPL) materials on September 16<sup>th</sup>. We understand that the Coast Guard must inform BHP by September 24<sup>th</sup> as to whether this application is complete regarding various federal requirements. The enclosure to this letter provides comments in this regard. Since we were given so little time to review these voluminous documents, our comments are necessarily general and may not be complete.

While the DPL discusses many relevant requirements for the necessary air and water permits, it does not include actual air and water permit applications. Some of the most important air elements that are missing include appropriate air modeling, a thorough BACT analysis, and a discussion of applicable SIP and NESHAP requirements. Some of the most important water elements that are missing include evaluations of all discharges.

If you have general questions about EPA's participation in this project, feel free to contact me at (415) 947-4115. For more detailed discussion, please contact Nahid Zoueshtiagh about air (972-3978), Eugene Bromley about water (972-3510), David Tomsovic about NEPA (972-3858), Margaret Alkon about legal air issues (972-3890) and Marcela von Vacano about legal water issues.

Sincerely,

A handwritten signature in black ink, appearing to read "Andy Steckel", is written over a horizontal line.

Andrew Steckel  
Acting Energy Coordinator

Enclosure.

cc: Stephen Billiot, Vice President, BHP Billiton  
300 Esplanade, Suite 1800, Oxnard, CA 93036

**Confidential Information** - Some information in the DPL materials is identified as confidential. BHP must explain why this information should be treated as confidential (e.g., confidential business information), and demonstrate that it complies with the appropriate legislation and implementing regulations (e.g., 40 CFR 2).

**Clean Air Act** - To construct and operate this facility, BHP will need federal Prevention of Significant Deterioration (PSD) and title V operating permits. To obtain these, BHP must submit complete applications to EPA as described in 40 CFR sections 52.21 and 71.5. Air permit applications should be provided to EPA as stand-alone documents. Alternatively, BHP may provide a summary document explaining where each permit application element can be found in a general document such as the DPL materials.

A complete PSD application includes, but is not limited to, the following components.

- A complete process description, including the submerged combustion vaporizer units.
- A complete air emissions summary, including construction emissions and all controlled and uncontrolled project emissions. It is not clear whether emissions estimates have been provided for all engines expected to operate at the project.
- A thorough regulatory analysis of applicable federal and state air pollution requirements.
- A complete Best Available Control Technology (BACT) analysis and determination.
- An air quality impact analysis which includes air modeling analysis. For this project, the Offshore Coastal Dispersion (OCD) model must be used.
- Additional impact analyses, including visibility, growth, soil, vegetation, and impacts on threatened and endangered species. The DPL materials provide some analysis, but we have not evaluated its adequacy because of our limited review time.

Some of the more critical items that are missing from the DPL materials for the PSD application are the BACT analysis, the air quality impact analysis, and the regulatory analysis of applicable rules from the State Implementation Plan (SIP). EPA staff met with BHP representatives from Entrix on May 22, 2003, and in that meeting and later emails and telephone calls, EPA and Entrix staff discussed the PSD requirements. We communicated to Entrix that the air model used in the impact analysis (ISCST3) is not appropriate, and that OCD must be used instead. We understand that Entrix intends to perform OCD modeling.

Although we understand that the intent of the Deepwater Port Act is for the DPL application to combine pre-construction applications for various federal permits, we note that the Title V operating permit is generally issued significantly after the PSD pre-construction permit. A Title V permit application consistent with 40 CFR 71.5 has not been included with the DPL materials. We encourage the applicant to submit this application, and associated fee information, after the PSD permit has been issued.

**Clean Water Act** - To operate this facility, BHP will need a National Pollutant Discharge Elimination System (NPDES) permit for each discharge. See 33 U.S.C. §§ 1311 and 1342. Discharge permits in federal waters will be issued by EPA, Region 9 while permits within the state's territorial seas (3 miles from shore) will be issued by the state. To obtain these permits, BHP must submit complete applications to EPA or the state as described in the Clean Water Act

and 40 CFR 122. Applications may be submitted as stand-alone documents, or may be appended to the DPL materials. A few specific significant items that are incomplete with respect to NPDES are identified below.

- The application must recognize all discharges needing a permit. Discharges mentioned in the text which require a permit but are not recognized on page 5-16 include the following:
  - Runoff from onshore construction. It appears that 1-5 acres would be disturbed, so the project would be considered "small construction" for purposes of permitting (EA page 3-21).
  - Firefighting water. The application mentions a continuous discharge; system testing discharges, if they occur, should also be described (page 2-14).
  - Although hydrotest water is recognized, maintenance pigging discharges must also be recognized (EA page 3-36). Chemical use, if any, must be clarified.
  - Drill cuttings and drilling muds discharged at the exit hole from the HDD (EA page 3-24/25).
  - Ballast water (EA page 3-33).
  - Black water (EA page 3-35); BHP must determine whether there will be discharges.

BHP should also clarify whether discharges from the following would occur.

- Cooling water from diesel generators (page 2-9 of application).
- Discharges from potable water-making (e.g., marine flash evaporators; page 2-9 of application).
- Forms 1 and 2D, as described in 40 CFR 122.21(a)(2)(i), are required for NPDES applications for new sources and new dischargers. Attachment 4 of the DPL materials includes only incomplete drafts of these forms. For example:
  - Form 2D reports "to be determined" for most items, does not complete section VI, and does not provide mass and pollutant concentrations for all discharges.
  - Forms 1 and 2D are unsigned.
  - Form 2F is required for storm water discharges, but not yet provided.
- EA Appendix A-1 states: "If complete information is not available by the time the Secretary must either approve or deny the (DPL) application...the license is conditioned upon the applicant receiving the required (NPDES) discharge permit from the EPA prior to the commencement of any discharge..." (Parenthesis added). It is our understanding that the license would not be granted until the necessary NPDES permit application information is provided and the appropriate permits issued.
- Other information noted as incomplete in the Deepwater Port Application concerns section 404 of the Clean Water Act. EPA needs additional information regarding the potential discharge of dredged or fill material into waters of the U.S., and, if necessary, a section 404 permit application to be submitted to the Army Corps of Engineers.

**National Environmental Policy Act (NEPA)** - EPA understands that the NEPA document for the proposed project will be an Environmental Impact Statement (EIS). Because EPA must issue permits for the facility, EPA would be an agency with "jurisdiction by law" for purposes of NEPA (40 CFR 1508.15). EPA expects to execute an inter-agency Memorandum of Agreement with the lead NEPA agency (U.S. Coast Guard) specifying EPA's roles and responsibilities regarding NEPA. This generally includes reviewing draft text of the draft and final EISs before the documents are publicly released. Another potential role is for EPA to assist the Coast Guard in preparing a response to comments on areas under EPA's jurisdiction. As a cooperating agency, EPA would not be responsible for preparing specific sections of the draft and final EISs. Please note that EPA's role as a cooperating agency does not relieve EPA of its statutory obligation to comment in writing on any project proposed under NEPA, including a determination by EPA on whether the proposed action could be unsatisfactory from the standpoint of public health or environmental quality, pursuant to Section 309(b) of the Federal Clean Air Act.



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November 17, 2005

## Solar's Day in the Sun?

High Costs of Supplying Electricity Embolden  
Two California Utilities to Bet on Alternative

By REBECCA SMITH

Staff Reporter of THE WALL STREET JOURNAL  
November 17, 2005; Page B1

Ambitious plans to cover two big swaths of California desert with solar dishes could finally help the energy-producing technology make the leap to industrial-scale development.

Stirling Energy Systems Inc., of Phoenix, hopes to construct 20,000 solar dishes covering four square miles of the Mohave Desert near Victorville, Calif., each dish pointing skyward to collect the sun's energy and convert it into electricity that would flow 80 miles south to power-hungry Los Angeles. The solar encampment, if eventually built, could produce 500 megawatts of electricity, enough to meet the daytime needs of 300,000 homes, doubling the state's solar capacity. The project cleared a hurdle last month when state regulators approved a 20-year power-purchase agreement between Stirling and Southern California Edison, a unit of **Edison International**.

A second project, involving Stirling and San Diego Gas & Electric Co., a unit of **Sempra Energy**, awaits approval. It calls for the purchase of 300 megawatts of solar power from a Stirling project in the Imperial Valley, east of San Diego, with an option to expand to as much as 900 megawatts -- the equivalent of two big gas-fired power plants.



Solar dishes used in Stirling model plant in Albuquerque, N.M.

The agreements, whose financial details haven't been disclosed, come as California has deepened its resolve to make more electricity from renewable sources, in part because of skyrocketing natural-gas prices after recent hurricanes along the Gulf Coast and also as a result of electricity blackouts in the state last summer. Another factor: Rising electricity prices are emboldening utilities to gamble on somewhat experimental technologies.

What is needed now is large-scale manufacturing of solar dishes to drive costs down, says Robert Boehm, director of the Center for Energy Research at the University of Nevada at Las

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Vegas. A hot zone, stretching from California to western Texas, looks ideal for "sun concentrating" technologies that need strong, direct sunlight to work well. In contrast, photovoltaic technology, found in rooftop solar panels, can make electricity under cloudy skies but isn't suited to powering whole cities.

The biggest challenge facing Stirling is to move its technology to mass production, says the company's chief executive, Bruce Osborn. To date, Stirling has made fewer than a dozen dishes, mostly for demonstration projects. Based on his two decades of experience in high-volume manufacturing and project management at Ford Motor Co., Mr. Osborn is confident the obstacles can be overcome.

If the two big projects are successful, they are likely to inspire more utility-scale solar projects elsewhere in the arid Southwest, where the population is growing rapidly. They would help solar energy take an important step forward, much like what happened in the early 1900s to the conventional power industry when it went from tiny generators supplying power to single sites to "central station" plants furnishing juice to thousands of customers.

#### ENERGY SAVERS

• Incentives Grow for 'Zero' Homes<sup>1</sup>  
11/17/05

This is the second time California has tried to make this jump. Following the energy crisis of the late 1970s, Israel-based Luz Solar Partners Ltd. built a 365-megawatt installation based on a type of solar-concentrating technology called a

"parabolic trough." The project, nine units installed from 1984 to 1990 near Barstow, Calif., subsequently went through other hands and then faced financial failure in the late 1990s, when federal subsidies expired. Today, a unit of **FPL Group Inc.**, based in Juno Beach, Fla., operates a majority of the units and sells the power to Edison under long-term contracts.

For 20 years, "solar power" has meant photovoltaic panels, like the ones found on homes in the Sunbelt states and on flat rooftops in states, like New Jersey, with policies favoring renewable power. Costs have come down dramatically as manufacturing methods have improved and volumes have grown.

But the industry has struggled in the years since the Reagan Administration, when Congress drastically reduced tax credits and subsidies. The U.S., which was manufacturing half of all photovoltaic panels as recently as a decade ago, now supplies only about 8% globally, as policies favoring renewable power in Japan, Germany and other countries have boosted production there.

The U.S. solar industry appears poised for a rebound, with the passage last summer of the Energy Policy Act, an omnibus energy bill that restored residential tax credits for solar installations and boosted federal support for commercial projects to levels not seen in decades.

It is difficult to compare the economics of electricity produced from photovoltaic panels versus that from solar dishes. That is because solar-panel electricity is made in small amounts and mostly is consumed on-site. Solar dishes, by contrast, make large sums of

electricity, at least in theory, and it is put directly on the transmission grid, like other big power plants. It is wholesale power, not retail power.

The hope is that solar dishes will one day make electricity for less than 10 cents a kilowatt hour, which is about what it costs to make electricity at modern, gas-fired power plants at today's fuel prices and less than half the cost of making it with photovoltaic panels.

Solar dishes hold the promise of being cheaper to build, maintain and operate than any other earlier form of solar power. Curved mirrors lining the inside surface of a Stirling dish focus sunlight on a receiver suspended above. Inside the receiver is a tank of hydrogen gas. When the gas heats, it expands and drives an engine, which in turn operates a generator to make electricity. John Bryson, Edison's chairman, said he was attracted to Stirling's technology because, "at least in the lab, it increases efficiencies to twice what we'd seen" from other solar technologies.

Edison once had rights to some of the technology that Stirling now is commercializing. Edison was a leader in solar development in the 1980s but abandoned the area when interest waned and the state began its march toward electricity deregulation in the early 1990s. In 1996, Edison sold its solar interests to Stirling for a "few hundred thousand dollars," according to Mr. Osborn. He said no Edison executives or managers are investors in his firm.

Sempra officials, meanwhile, acknowledge the risks of relying on dishes that haven't been proven commercially feasible. But one of California's policy goals "is to have utilities enter into contracts that are helpful to making new technologies economic," says Terry Farrelly, a Sempra vice president of energy procurement. California's goal is to obtain at least 20% of its electricity from renewable sources by 2010, up from the current level of about 12%. In June, Gov. Arnold Schwarzenegger announced he wants the state to achieve a 33% target by 2020.

Utilities in other states have been nudging big solar projects forward, too. **Sierra Pacific Resources**, of Reno, Nev., has been working with Solargenix Energy, based in Raleigh, N.C., and formerly Duke Energy's solar-power unit, to get a 55-megawatt project built in Nevada. Arizona Public Service, a unit of **Pinnacle West Capital Corp.**, is working on half a dozen solar technologies including one that would use solar dishes to heat air, not hydrogen, to run a turbine. "We love the idea of a dish and think it's no more complicated than a car," says Peter Johnston, head of APS's research effort.

In addition to manufacturing hurdles, other challenges remain. Dishes need a lot of land, so anything that pushes up land prices or raises environmental concerns could hurt their prospects. And they need big transmission lines to get the power to users. Nevertheless, some solar-power advocates think this is the best time in nearly 30 years to push for large-scale development. Says Doug Faulkner, an assistant secretary in the U.S. Energy Department: "Things are starting to line up."

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